Flexible Transmission Network Planning Considering the Impacts of Distributed Generation

Junhua Zhao and John Foster

Energy Economics and Management Group

School of Economics

University of Queensland

Abstract

The restructuring of global power industries has introduced a number of challenges, such as conflicting planning objectives and increasing uncertainties, to transmission network planners. During the recent past, a number of distributed generation technologies also reached a stage allowing large scale implementation, which will profoundly influence the power industry, as well as the practice of transmission network expansion. In the new market environment, new approaches are needed to meet the above challenges. In this paper, a market simulation based method is employed to assess the economical attractiveness of different generation technologies, based on which future scenarios of generation expansion can be formed. A multi-objective optimization model for transmission expansion planning is then presented. A novel approach is proposed to select transmission expansion plans that are flexible given the uncertainties of generation expansion, system load and other market variables. Comprehensive case studies will be conducted to investigate the performance of our approach. In addition, the proposed method will be employed to study the impacts of distributed generation, especially on transmission expansion planning.

I. INTRODUCTION

The restructure and deregulation of the global power industry have introduced fundamental changes to the practices of power system planning. Traditionally, generation expansion and transmission expansion are sub-tasks of a power system planning process performed by a regulated power utility. In the new market environment, however, transmission expansion planning is usually performed separately by transmission network service providers (TNSPs), while generation expansion becomes the task of generation companies or investors. These changes have imposed new objectives and uncertainties on transmission planners, making the transmission planning problem much more difficult.

Generally speaking, *transmission expansion planning (TEP)* aims at addressing the problem of expanding the power transmission network to better serve growing demand for electricity while satisfying a number of economic and technical constraints [1]. In the regulated environment, the problem can be formulated as one of minimizing expansion cost subject to the reliability and other system constraints. In a deregulated environment, the situation becomes more complicated since transmission planners have to take into account the preferences of all market players and try to simultaneously satisfy several different planning objectives. The possible planning objectives include [2]: facilitating market competition; providing nondiscriminatory access to cheap generation for all customers; enhancing reliability and maintaining sufficient capacity reserves; enhancing system security, etc. Some of these objectives can conflictr.

Another challenge is the increasing uncertainty involved in the planning process. In the contemporary environment, although generation planning is undertaken, transmission planning is no longer coordinated with generation planning by a single planner. It is therefore difficult for the transmission planner to access accurate information concerning generation expansion. Therefore, future generation capacities and system load flow patterns become more uncertain. Other possible sources of uncertainty include [3]:

- System load;
- Bidding behaviors of generators;
- Availability of generators, transmission lines and other system facilities;
- Installation/closure/replacement of other transmission facilities;
- Carbon prices and other environmental costs;
- Market rules and government policies.

An important issue not listed above is the potential large-scale penetration of *distributed generation* (DG) technologies. Traditionally, the global power industry has been dominated by large, centralized generation units which are able to exploit significant economies of scale. In recent decades, however, the centralized generation model has been criticized for its costs, security vulnerability and environmental impacts, while DG is now expected to play an increasingly important role in the future provision of electricity supply. However, any large-scale implementation of DG will cause significant changes in the power industry, and also deeply influence the transmission planning process. For example, DG can reduce local power demand and, thus, it can potentially defer investments in the transmission and distribution sectors. On the other hand, when the penetration of DG in the market reaches a certain level, its suppliers will have to get involved in the spot market and trade the electricity through the transmission and distribution networks, which may then need to be further expanded. Therefore, it is important to investigate the impacts of DG on transmission planning and take into account the uncertainty that it brings to the planning process.

In this paper, a novel approach to transmission network expansion planning is proposed. Two stochastic processes, namely *geometric Brownian motion* and a *mean reverting* process, are employed to model system load and market price. Based on these stochastic models, the *risk neutral valuation* technique is applied to obtain the values of different generation investment options in different locations. The estimated investment values are then used to generate future generation scenarios. A multi-objective optimization model is introduced to model the TEP problem. A Monte Carlo based approach is employed to simulate a transmission companyôs behavior over a given planning horizon and to assess the flexibility of a given transmission expansion plan. The results of comprehensive case studies to assess the performance of the propose method are reported. The proposed method is then applied to investigate the potential impacts of DG on transmission planning.

The rest of this paper is organized as follows: a comprehensive literature review is provided in Section II. In Section III, the proposed planning method is discussed in more detail. Comprehensive case studies are presented in Section IV. In particular, the impacts of DG on transmission planning are assessed, using the proposed method. Section V contains our conclusions.

II. LITERATURE REVIEW

In recent years, extensive research has been conducted on transmission planning due to its importance in electricity market operation. The literature on transmission planning can be grouped into the following three areas:

Optimization Methods ï since TEP involves an optimization problem, extensive studies have been conducted on applying different optimization techniques to obtain appropriate expansion plans. These methods can be further classified into two types: mathematical optimization and heuristic optimization. The mathematical optimization models find an optimum expansion plan by using a calculation procedure that solves a mathematical formulation of the TEP problem. This approach includes linear programming [4], dynamic programming [5], nonlinear programming [6], mixed-integer programming [7-8], benders [9] and hierarchical decomposition [10]. In contrast, heuristic methods select optimum expansion plans by performing local searches with the guidance of some logical or empirical rules [11]. The heuristic optimization techniques that have been applied to solve the TEP problem include: sensitivity analysis models [12], genetic algorithms [13], simulated annealing [14], fuzzy set theory [1], differential evolution [15] and the TS algorithm [16]. Moreover, since TEP is usually modeled as a multi-objective optimization problem, several multi-objective optimization techniques have also been applied, such as the weighted sum method [17], the weighted sum metric method [17] and multi-criteria decision making [18].

Static and Dynamic Planning ï transmission planning can be categorized as static or dynamic based on the manner in which the planning horizon is treated. Static planning [11] aims at identifying the size and location of the optimal expansion plan at a certain point in time. On the other hand, dynamic planning [19] involves consideration of a planning horizon of several years and, besides size and location, it also determines when to implement an expansion plan.

Modeling Uncertainties ï a main challenge of TEP in the deregulated environment is dealing with the increasing uncertainty involved in the planning process. A number of probabilistic approaches [2, 20] have been proposed to handle random uncertainties [2] such as the uncertainties of load, generation capacities and generator availability. Decision analysis [21] can be applied to take into account non-random uncertainties. Stochastic programming [22] can be employed to find some policy that is feasible for all (or almost all) the possible data instances and maximizes the expectation of some function that includes both decisions and random variables. In contrast to the above methods, we propose in this paper that, given the increase in uncertainty the contemporary context, an expansion plan should be selected on the basis of its *flexibility* [15]. The most flexible plan is defined as the plan that can adapt to any potential scenario at minimum adaptation cost.

The flexibility criterion is chosen because probabilistic and decision analysis methods do not consider the possible consequences of implementing an expansion plan. In a deregulated market, transmission planning usually has to simultaneously satisfy a number of different planning objectives such as: enhancing market competition, improving reliability and security, etc. Since the implementation of an expansion plan will usually take several years, the optimal plan that is identified by probabilistic or decision analysis methods may not be able to satisfy the planning objectives after implementation due to significant market uncertainties. Further expansion will then become necessary and this cost should be taken into account and used to measure the value of flexibility. Thus, we can establish a framework for flexible transmission planning and further develop the method to handle more complicated cases.

It is expected that the large scale penetration of DG will significantly change the power industry. Therefore, increasing efforts have been made recently to investigating the impacts of DG on all aspects of the power market. Generally speaking, distributed generation is defined as the presence of generation units that are connected to the power grid either on the customer side or into the distribution network [23]. The size of a typical DG system usually ranges from 1 KW to 5 MW, while a large DG system can reach a capacity up to 300MW [23]. DG can be categorized as renewable, such as wind or solar power, or non-renewable, such as the internal combustion engine (ICE) and micro-turbines.

Since the market penetration of DG is still low in most countries, a number of studies [24-25] have been conducted to investigate the barriers to DG penetration and the factors that can contribute to DG deployment. A number of economic analyses [26-27] have also been conducted to study the market performance of DG systems. In addition, since DG is usually connected at the distribution level, extensive research [28, 38-39] has been conducted to investigate the impacts of DG on distribution network planning. These studies have usually focused on determining the optimal size and location of DG units in the distribution network from the distribution companyös point of view. Some studies [29-30] also have been performed to understand the impacts of DG on the system side, such as on reliability, system security and power quality.

Little research has been done to investigate the impacts of DG on the transmission network. When its market share is still small, DG can simply be modeled as negative load in the system. However when the market penetration of DG reaches a certain level and the electric utilities implement DGs as standard investments in generation capacity [23], then it will be necessary to get involved in the spot market and sell power through the transmission network. This will possibly require modifications to the current market dispatch mechanism [31]. To investigate the potential of large impacts of DG on the transmission network, comprehensive quantitative analysis will need to be performed.

III. THE PROPOSED PLANNING APPROACH

In this section, the proposed method is introduced in more detail. We firstly introduce the main idea of the approach and then the main steps of the method are introduced in subsections.

A. Overview of the Proposed Planning Method

The first task is to evaluate generation investment options in different locations of the network. These options include both traditional generation techniques and DG. Future generation scenarios can then be based on the investment valuation results. A multi-objective optimization model is formulated to find several expansion plans that are quasi-optimal at the beginning of the planning horizon. To take into account market uncertainties, a Monte Carlo simulation is performed to generate N market scenarios over the entire planning horizon. Each scenario consists of a chosen generation capacity, system load and market price path withand the application of different market rules such, as different feed-in-tariff (FIT). It is checked whether the planning objectives have been satisfied during the entire planning horizon and re-expansion is performed if the objectives are not met. The re-expansion costs of N iterations form a distribution of adaptation costs for a given candidate plan, which measures the planôs flexibility.

The major steps of this proposed method are listed as follows and illustrated in Figure 1:

1. Build models for system load and market price at different locations in the market. These models are used in the following steps when doing investment valuation and market simulation.
2. Evaluate potential investment options and select several options that are relatively

attractive.

3. Employ the multi-objective optimization model to generate several candidate expansion plans.

4. For each candidate plan, perform Monte Carlo simulation to generate N market scenarios.

5. For each plan under a scenario, re-expand the network if planning objectives are not reached and calculate the adaptation cost.

6. Obtain a probability distribution of the adaptation cost of each candidate plan and select the optimal expansion plan based on its flexibility.

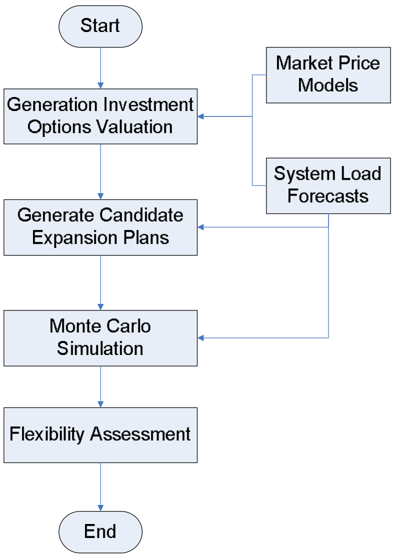

Figure 1 The Planning Method

B. Models for System Loads and Market Prices

Two stochastic processes are proposed to model system load and the nodal price at each bus of the system. Investment valuation and market simulation are based on these two models. For each bus i in the system, the load is modeled by the widely used *Geometric Brownian motion (GBM)* process [32] as follows:

$$dP_{Di} = u_{Di}P_{Di}dt + \sigma_{Di}P_{Di}dX \tag{1.1}$$

$$dX \sim N(0, dt) \tag{1.2}$$

where P_{Di} represents the power demand at bus i; dX is the standard *Wiener process* [32], which essentially follows a normal distribution with zero mean and a variance of dt.

For each bus *i*, the nodal price can be modeled by a *mean-reverting* [32] process, which is often an appropriate model for energy prices [32]. The model can be written as follows:

$$\frac{dZ_i}{Z_i} = k_i(u_{Zi} - Z_i)dt + \sigma_{Zi}dX \tag{2}$$

Here Z_i is the nodal price at bus *i*; u_{Zi} and σ_{Zi} are long term mean and variance of the process; k_i represents the mean reversion rate. The price Z_i probabilistically tends to increase if it is below u_{Zi}, and decrease if it is above. The mean reversion rate k determines the speed with which Z_i converges to the long term mean. u_{Zi} is usually assumed to be a function of time. Since the market price generally tends to increase in the long term, we assume that u_{Zi} is a function of the bus load P_{Di}. This function relationship can be estimated econometrically..

The parameters of models (1) and (2) can be estimated using the Maximum Likelihood Estimation (MLE) method. The essential idea of MLE is to select parameters that make the observed data most likely to occur.

To obtain the ML estimators, the likelihood functions of the models should be derived first. Assume that a historical load series $\check{P}_{Di}(t), t = 0,1 \ldots T$ has been observed. Transform model (1) into discrete form:

$$P_{Di}(t) = P_{Di}(t-1) + u_{Di} \times P_{Di}(t-1) + \varepsilon_t \tag{3.1}$$

$$\varepsilon_t \sim N(0, (\sigma_{Di} P_{Di}(t-1))^2) \tag{3.2}$$

Obviously $P_{Di}(t)$ is conditionally normal as well, with mean $P_{Di}(t-1) + u_{Di} \times P_{Di}(t-1)$ and variance $(\sigma_{Di}P_{Di}(t-1))^2$. The likelihood function of model (3) given observed data $\check{P}_{Di}(t), t = 0,1 \ldots T$ can therefore be calculated as:

$$L(\{\check{P}_{Di}(t)\}_1^T; \vec{\theta}) = f_1(\check{P}_{Di}(1) \mid \check{P}_{Di}(0); \vec{\theta}) \times f_2(\check{P}_{Di}(2) \mid \check{P}_{Di}(1); \vec{\theta}) \ldots\ldots$$
$$\times f_T(\check{P}_{Di}(T) \mid \check{P}_{Di}(T-1); \vec{\theta})$$

$$= \prod_{t=1}^{T} \frac{1}{\sigma_{Di}\breve{P}_{Di}(t-1)\sqrt{2\pi}} e^{-\frac{(\breve{P}_{Di}(t)-(\breve{P}_{Di}(t-1)+u_{Di}\times\breve{P}_{Di}(t-1)))^2}{2(\sigma_{Di}\breve{P}_{Di}(t-1))^2}} \tag{4}$$

where $\vec{\theta} = (u_{Di}, \sigma_{Di})'$.

Similarly, assume that a historical nodal price series $\breve{Z}_i(t),\ t = 0,1 \ldots T$ has been observed. The likelihood function of model (2) can be given as:

$$L(\{\breve{Z}_i(t)\}_1^T; \vec{\vartheta}) = \prod_{t=1}^{T} \frac{1}{\sigma_{Zi}\breve{Z}_i(t-1)\sqrt{2\pi}} e^{-\frac{(\breve{Z}_i(t)-\breve{Z}_i(t-1)-k_i(u_{Zi}-\breve{Z}_i(t-1))\times\breve{Z}_i(t-1))^2}{2(\sigma_{Zi}\breve{Z}_i(t-1))^2}} \tag{5}$$

where $\vec{\vartheta} = (u_{Zi}, \sigma_{Zi})'$.

The ML estimators of parameters $\vec{\theta} = (u_{Di}, \sigma_{Di})'$ and $\vec{\vartheta} = (u_{Zi}, \sigma_{Zi})'$ can be obtained by maximizing likelihood functions (4) and (5) respectively. This optimization problem can be easily solved with a nonlinear optimization algorithm, such as a genetic algorithm.

C. Generation Options Valuation

Generation capacity is a major uncertain factor that can significantly affect transmission planning decisions. In a deregulated market, the transmission company is not involved in the decision process leading to generation investments, although TNSPs may conduct studies when potential generators request a connection point to the existing network. It is therefore difficult for the TNSPs to take into account future generation capacity in the planning process. We solve this problem by comparing the investment values of different generation technologies at different locations of the network and selecting the generation options with relatively higher values to construct future generation scenarios.

The value of an investment in a generation plant usually is measured by its net present value (NPV). In order to calculate the cash flows for the entire life cycle of the plant [32] it is necessary to take into account the capital cost, the operation and maintenance (O&M) cost, the fuel cost and the nodal price. NPV is obtained by summing the discounted cash flows. The generation options with higher NPVs are considered to be more attractive for investors and, thus, more likely to occur in the market. The generation options with M highest NPVs are selected for constructing future generation scenarios. We employ this method to evaluate traditional generation technologies such as coal-fired and gas plants.

DG units can be valued in two different ways. When the market share of DG is small, a DG unit is usually modeled as a negative load in the distribution network and a distribution company implements it only if its cost is lower than the cost of buying electricity from the market. If so, it expands the distribution network correspondingly [28]. When the penetration of DG reaches a certain level, a DG can be considered as a standard generation plant and its value can be determined by the NPV method discussed below.

We can calculate the value of building a generation plant with technology j at bus i as follows:

1. Derive the *risk neutral process* [32] from model (2). This process can be given as:

$$\frac{dZ_i}{Z_i} = (k_i(u_{Zi} - Z_i) - \sigma_{Zi}\lambda_i)dt + \sigma_{Zi}dX \tag{6}$$

where λ_i is the *market price of risk* [32] of the nodal price Z_i.

2. Employ model (6) to generate a market price path over T consecutive years, where T is the life cycle of the plant.

3. Calculate the cash flow CF_t of plant j at year t, CF_t as:

$$CF_t = (Z_i(t) - C_{VO\&M} - C_{fuel}) \times f_{cap} \times 8760 - C_{FO\&M} \tag{7}$$

where $C_{VO\&M}, C_{FO\&M}, C_{fuel}$ are the variable operation and maintenance cost, the fixed operation and maintenance cost, and the fuel cost of technology j respectively. f_{cap} represents the typical *capacity factor* [32] of technology j.

4. The NPV can be calculated as:

$$NPV_{i,j} = C_{cap} + \sum_{t=1}^{T}(CF_t \times e^{-rt}) \tag{8}$$

where r is the *risk-free interest rate* [32] and C_{cap} is the capital cost of technology j.

5. Repeat steps (2)-(4) for N iterations, obtain the average value of NPVs.

The above procedure is based on the *risk neutral valuation* [32] approach. Generally speaking, risk-neutral valuation assumes that electricity markets are risk-neutral. All investments will therefore yield an identical return of the risk free interest rate. Theoretically, the risk-neutral assumption is equivalent to a óno arbitrageô assumption. In electricity markets however, the non-storability of electricity weakens the non-arbitrage assumption. The market price of risk should therefore be introduced to adjust the drift rate of the risk-neutral process.

D. Transmission Expansion Planning Model

A transmission expansion planning model is proposed in this sub-section. The main idea of the model is to minimize the expansion investment subject to power flow [40] and other system constraints. As discussed in the Introduction, Planners in the deregulated environment may need to consider several different objectives. We can handle multi-objectives by adding a constraint into the model for each objective. For example, to consider reliability, we will add a constraint that the expansion plan must reach a minimum reliability requirement. The model is as follows:

Minimize

$$O = C^T \eta \tag{9.1}$$

Subject to

$$P_{Gi} - P_{Di} = \sum_{n=1}^{N} |Y_{in} V_i V_n| \cos(\theta_{in} + \delta_n - \delta_i) \tag{9.2}$$

$$Q_{Gi} - Q_{Di} = \sum_{n=1}^{N} |Y_{in} V_i V_n| \sin(\theta_{in} + \delta_n - \delta_i) \tag{9.3}$$

$$S_{ij}^{f} \le S_{ij}^{\max} \tag{9.4}$$

$$V_i^{\min} \le V_i \le V_i^{\max} \tag{9.5}$$

$$P_{Gi}^{\min} \le P_{Gi} \le P_{Gi}^{\max}$$

(9.6)

$$Q_{Gi}^{\min} \le Q_{Gi} \le Q_{Gi}^{\max}$$

(9.7)

$$Y_{ij} = -(y_{ij}^0 + \eta_{ij}\tau_{ij}), (i \ne j)$$

(9.8)

$$Y_{ii} = y_{i0} + \sum (y_{ij}^0 + \eta_{ij}\tau_{ij}), (i \ne j)$$

(9.9)

$$O_k \ge O_k^{\min}, k = 1...K$$

(9.10)

where

P_{Gi}, Q_{Gi}	Real and reactive power outputs of generator *i*;
P_{Di}, Q_{Di}	Real and reactive power demands at bus *i*;
Y	Bus admittance matrix of the system;
θ_{in}	Angle of elements Y_{in} in Y;
τ_{ij}	New circuit admittance between of branch $i-j$;
O_k	Measure of objective *k* after expansion;
$O_{\min}$	Minimum planning requirement for objective *k*;

Detailed discussion about the above AC OPF model can be found in [40]. In model (9), the objective (9.1) represents the expansion investments. Constraints (9.2)-(9.7) correspond to the typical AC power flow. Equations (9.8) and (9.9) set the new admittance matrix after expansion. Constraint (9.10) ensures that the system satisfies the minimum planning requirements for all *k* objectives after expansion. The model aims to minimize expansion investment while satisfying all the pre-defined expansion objectives. In this paper, two main objectives, enhancing reliability and market competition, are considered. However, other objectives can also be added into the model in a similar way, which makes the model highly flexible in practical applications.

Model (9) is a constrained nonlinear optimization problem which is highly complex. To solve this problem, a *particle swarm optimization (PSO)* algorithm [37] is employed. Particle swarm optimization is a stochastic population-based algorithm based on social-psychological principles. A problem is given, and some way to evaluate a proposed solution to it exists in the form of a fitness function. A communication structure or social network is also defined, assigning neighbors for each individual to interact with. Then a population of individuals, defined as random guesses at the problem solutions, is initialized. These individuals are candidate solutions. They are also known as the particles, hence the name particle swarm. An iterative process to improve these candidate solutions is set in motion.

The particles iteratively evaluate the fitness of the candidate solutions and remember the location where they had their best success. The individual's best solution is called the particle best or the local best. Each particle makes this information available to their neighbors. They are also able to see where their neighbors have had success. Movements through the search space are guided by these successes, with the population usually converging, by the end of a trial, on a problem solution better than that of a non-swarm approach using the same methods. It should be noted that other *evolutionary computation (EC)* methods can be used here as well. Since the main purpose of this paper is not on application and choice of ECs, discussions of this aspect is not included in greater details.

E. Assessing the Flexibility of Expansion Plans

As discussed above, the market environment is highly uncertain and somewhat unpredictable. Since the implementation of an expansion plan usually takes several years, during which the market situation may have changed significantly, the planning objectives may not be met when the expansion is completed. Flexibility in an expansion plan is therefore very important. The flexible expansion plan should ensure that, if unexpected future scenarios occur, further expansion can be done in a timely and cost-effective way.

We have proposed that the flexibility of an expansion plan can be measured by its maximum re-expansion cost, given all possible future scenarios [15]. In practice however, this approach may become computationally infeasible for a large system due to the very large number of potential scenarios. In this paper, we tackle this problem by employing Monte Carlo simulation to obtain an approximate value for the maximum re-expansion cost. Moreover, the distribution of the re-expansion costs given by the simulation also provides valuable information for flexibility assessment.

In the simulation, random and non-random uncertainties are treated differently. Random uncertainties, such as the system load and the market price, are modeled with the stochastic processes introduced in previous sections; and future scenarios consist of the load and price paths generated with these processes. Non-random uncertainties are modeled by assuming each possible event is equally likely. For example, we can select M generation investment options with the method described in Section III.C. Then, in each year of a scenario, we can randomly select one investment to implement and study its impacts. Changes in market rules can also be modeled in this way. For example, over the planning horizon we can randomly select a year, in which a feed-in-tariff (FIT) schema is introduced. The procedure of the simulation is illustrated in Fig. 2.

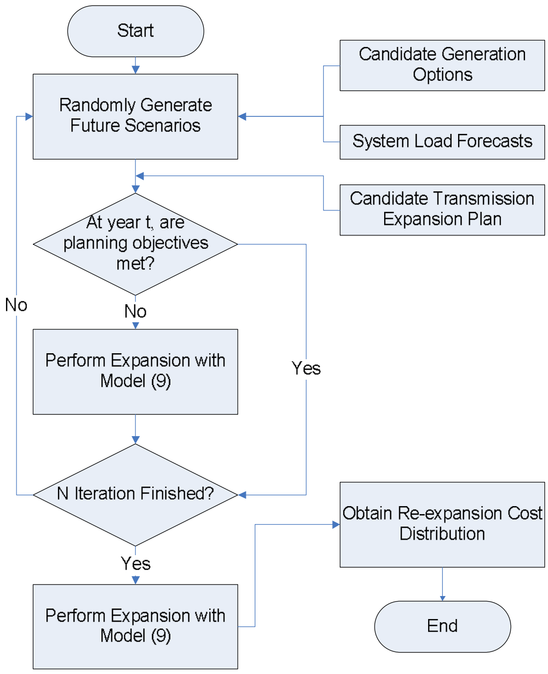

Figure 2 The Procedure of Employing Monte Carlo Simulation for Flexibility Assessment

F. Reliability Assessment

Maintaining system reliability is a core task in transmission planning. Reliability can be seen as the degree of assurance in providing customers with continuous service of satisfactory quality. Power system reliability has two dimensions: *adequacy and security*. Adequacy measures the generation and transmission capacities of the system under static conditions, without considering system disturbances. On the other hand, security represents the ability of the system to respond to disturbances in the system. In this paper, system reliability is measured by *expected unserved energy (EUE)* [33]. This is the expected amount of power that is not supplied due to inadequate generation and transmission capacities. Given a market scenario, as formulated in the above section, a Monte Carlo simulation can be used to randomly generate different system load levels and *AC optimal power flow* (OPF) [15] can be calculated to find the amount of unsupplied energy. By calculating the average of the unsupplied energy in the simulation the EUE can be finally obtained.

G. Market Competition

A core task of the transmission network is to provide non-discriminatory access to generation resources and enhance competition among market participants. Theoretically, the nodal prices at all buses in the system will be equal if the system has infinite transmission capacity. Insufficient transmission capacity will cause congestion and give large generators opportunities to exercise market power and raise the spot price [2]. Therefore, an important objective of transmission planning is to mitigate congestion and enhance market competition.

In light of the above consideration, congestion cost can be employed to assess the impacts of new expansion plans on market competition. The congestion cost of a transmission line is defined as:

$$C_i = (price_{i2} - price_{i1}) \times P_{i1,i2} \tag{10.1}$$

where C_i is the congestion cost of line *i*, $price_{i2}, price_{i1}$ are the locational prices of end buses of line *i*, and $P_{i1,i2}$ is the power transferred through line i. The total congestion cost of the system is:

$$C = \sum_{i \in N} C_i \tag{10.2}$$

IV. CASE STUDIES

A. Overview of Case Studies

The proposed planning approach was tested on the IEEE 14 bus system [15]. A diagrammatic representation of the system is given in Fig. 3. The system data of generators and loads are set as Tables I and II. The total generation capacity of the system is 952.4 MW, while the total system load is 638 MW. The EUE and congestion cost of the base case is calculated as 28948 MWh and 4393.7 \$/Hour respectively. We assumed that all new transmission lines will have a nominal voltage of 345 KV and a capacity of 50 MVA. The construction cost was assumed to be 45-50 M\$/100km. The construction time is proportional to the length of the line.

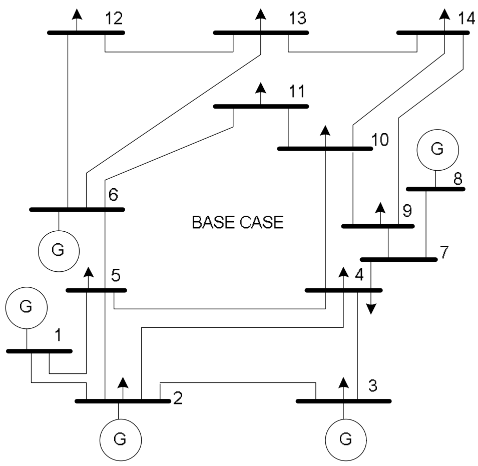

Figure 3 IEEE 14 Bus System ï Base Case

TABLE I GENERATORS DATA

Bus No.	P_{max} (MW)	P_{min} (MW)	Q_{max} (MVAR)	Q_{min} (MVAR)
1	332.4	0	10	0
2	200	0	50	-40
3	140	0	40	0
6	140	0	54	-6
8	140	0	54	-6

TABLE II LOADS DATA

Bus No.	**P_d (MW)**	**Q_d (MVAR)**
2	21.7	12.7
3	194.2	29
4	47.8	-13.9
5	157.6	11.6
6	30.2	17.5
9	119.5	16.6
10	9	5.8
11	3.5	1.8
12	26.1	11.6
13	13.5	5.8
14	14.9	5

In our case studies, four generation technologies were considered, including a black coal fire plant, a combined cycle gas turbine (CCGT) plant and two distributed generation technologies ï concentrated solar thermal (CST) and wind power. We assumed possible generation investment options and their technical parameters as specified in Table III. The cost data were obtained from [34-36]. We firstly conducted simulations without considering distributed generation, and investigated the performance of our approach. The approach was then employed to study the impacts of DG on the network.

TABLE III NEW GENERATOR CHARACTERISTICS

Technology	Capital Cost (M$/MW)	Fixed Generation Cost ($/MW/Year)	Variable Generation Cost ($/MWh)	Life Cycle (Year)	Capacity (MW)	Capacity Factor (%)
Black Coal Fire	2.239	7200000	17.02	40	200	85
CCGT	1.314	1550000	38.21	30	150	60
CST	4.9	-	45.5	25	20×5	56
Wind	2.8	600000	-	25	20×5	40

B. Case 1 - Flexibility Assessment

We firstly tested the proposed method by assuming that only coal fire plant and CCGT are implemented in the market. The planning horizon T was set at 10 years. By applying the investment valuation method, discussed in Section III.C, 8 investment options with highest values were isolated (these are listed in Table IV). Based on the data in Table III, coal fire plant is generally more attractive than CCGT for investors, which matches the real market situation. Moreover, it can be observed that building new generators in buses 2, 3, and 6 are relatively more economical, while bus 1 is not preferable since it already has a high generation capacity.

Model (9) was then employed to select the candidate expansion plans which can be implemented at the beginning of the planning horizon ($t = 0$). As observed in Table V, plan 4 has the minimum construction cost. Since model (9) has ensured all five plans satisfy the planning objectives, given the information at $t = 0$, Plan 4 is optimal if future uncertainties are not considered.

TABLE IV GENERATION VALUATION RESULTS FOR CASE 1

Technology	Bus No.	Capacity (MW)	NPV (M$)
Black Coal Fire	3	200	1435.56
Black Coal Fire	2	200	1372.39
Black Coal Fire	6	200	1214.61
Black Coal Fire	8	200	933.68
Black Coal Fire	1	200	458.48
CCGT	3	150	183.3
CCGT	2	150	155.11
CCGT	6	150	91.13

TABLE V CANDIDATE EXPANSION PLANS

Plan No.	Transmission Lines	Construction Cost (M$)	Construction Time (Year)
1	(1,3) (2,3)	450	4
2	(1,3) (6,11)	396	6
3	(1,4) (3,9)	330	4
4	(6,11) (8,14)	306	4
5	(1,4) (6,9) (6,11)	411	3

We then employed the flexibility assessment approach discussed in Section III.E to obtain the distributions of the re-expansion costs of five candidate plans. As shown in Table VI, in the assumed planning horizon, Plan 4 needs, at most, 2095 M$ of further expansion cost to satisfy planning objectives, which is much higher than the maximum re-expansion costs of 1288 and 1395 M$ of candidate Plans 1 and 2. The mean re-expansion cost of Plan 2 is also significantly less than Plan 4, while Plan 1 has a similar mean re-expansion cost to Plan 4.

TABLE VI RE-EXPANSION COSTS OF CANDIDATE PLANS

Plan No.	Maximum Re-expansion Cost (M$)	Minimum Re-expansion Cost (M$)	Mean Re-expansion Cost (M$)
1	1288	550	817
2	1395	396	648.7
3	1965	330	876.5
4	2095	456	782.2
5	1848	411	889

Plotting the empirical *cumulative distribution functions (CDF)* of Plans 1, 2 and 4 gives us a clearer idea about their flexibilities. As clearly observed in Figs 4 - 6, if Plan 1 is implemented initially, there is only around a 10% probability that the further expansion cost will exceed 1000 M$. This probability is less than 5% for Plan 2. For Plan 4, however, the probability is around 20%. Taking into account both the distributions and maximum re-expansion costs, Plans 1 and 2 are much more flexible than Plan 4, although it has the minimum initial cost.

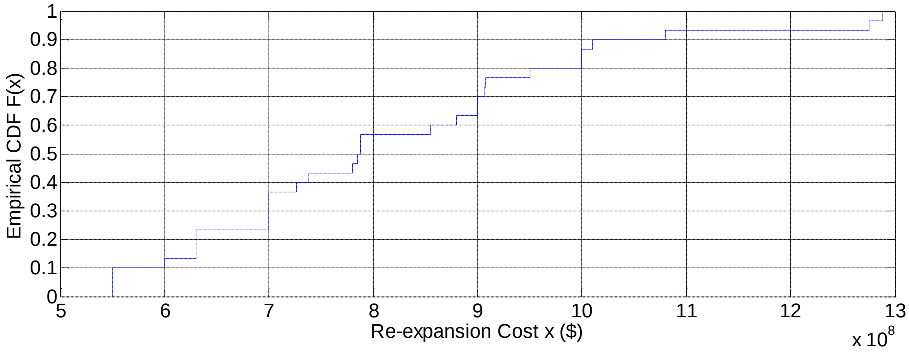

Figure 4 Empirical CDF of Plan 1

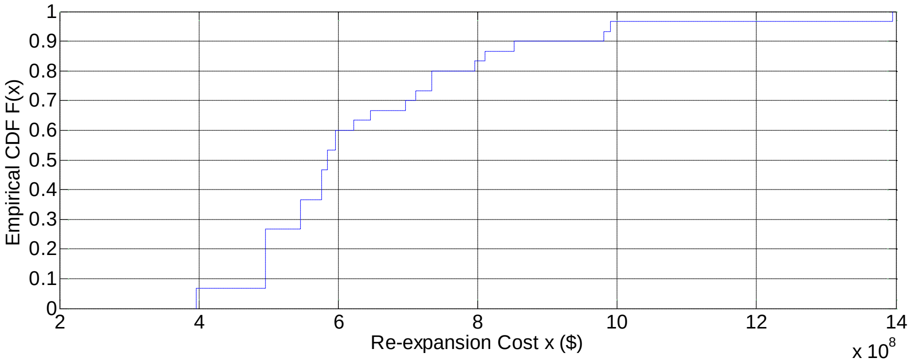

Figure 5 Empirical CDF of Plan 2

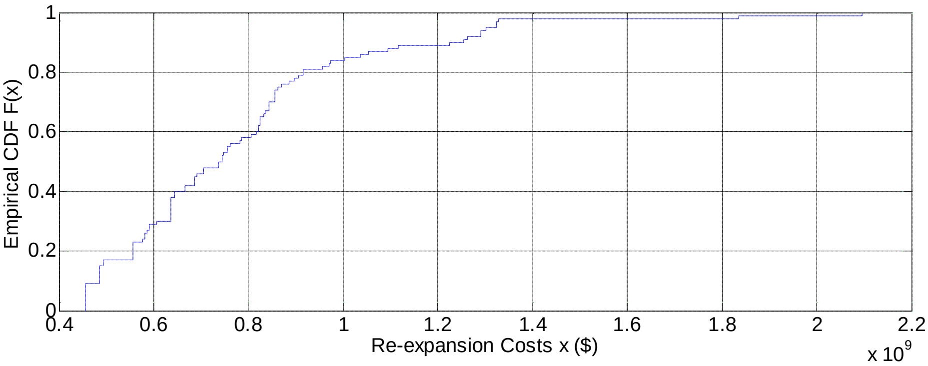

Figure 6 Empirical CDF of Plan 4

C. Case 2 – Distributed Generation

In the second case, DG was taken into account. We assumed that CST and wind power plants are only built at load buses (Buses 4, 5, 7, 9, 10-14). Similarly, the generation valuation method was applied to determine the generation options with highest values in the market. To consider possible government policies for encouraging the adoption of renewable energy, a *feed-in tariff (FIT)* factor was assumed for solar and wind power. The prices of solar and wind are the spot market price multiplied by their specific FIT factors. The candidate generation options, given different FIT factors, were then calculated, as given in Tables VII and VIII. As observed, wind power can replace CCGT if a 2 times feed-in tariff is introduced, while CST can become competitive with CCGT only if a 3 times feed-in tariff is implemented. CST can start to replace coal fire after its FIT factor reaches 4. These results clearly indicate that the two renewable technologies are not competitive enough yet with fossil fuel generation technologies, given their current costs. Strong government support is still necessary for promoting their market penetration.

TABLE VII GENERATION VALUATION RESULTS (FITWIND = 2, FITSOLAR = 2)

Technology	Bus No.	Capacity (MW)	NPV (M$)
Black Coal Fire	3	200	1435.56
Black Coal Fire	2	200	1372.39
Black Coal Fire	6	200	1214.61
Black Coal Fire	8	200	933.68
Black Coal Fire	1	200	458.48
CCGT	3	150	183.3
Wind	14	100	163.21
Wind	9	100	155.2

TABLE VIII GENERATION VALUATION RESULTS (FITWIND = 2, FITSOLAR = 3)

Technology	Bus No.	Capacity (MW)	NPV (M$)
Black Coal Fire	3	200	1435.56
Black Coal Fire	2	200	1372.39
Black Coal Fire	6	200	1214.61
Black Coal Fire	8	200	933.68
Black Coal Fire	1	200	458.48
CST	9	100	356.6
CST	14	100	356.4
CST	4	100	354.9

TABLE IX GENERATION VALUATION RESULTS (FITWIND = 4, FITSOLAR = 4)

Technology	Bus No.	Capacity (MW)	NPV (M$)
Black Coal Fire	3	200	1435.56
Black Coal Fire	2	200	1372.39
Black Coal Fire	6	200	1214.61
Black Coal Fire	8	200	933.68
CST	13	100	744.4
CST	14	100	735.72
CST	9	100	735.71
CST	7	100	735.6

Our approach was then applied to study the impacts of DG on transmission planning. Unlike Case 1, in this study no initial expansion plans were implemented at $t = 0$. After candidate generation options were selected, the approach illustrated in Fig.2 was performed directly to simulate transmission expansion actions and to obtain the expansion cost distribution. Higher expansion costs indicate stronger needs for network expansion. The expansion cost distribution in the base case without DG units installed is given in Fig. 7. Several different scenarios of DG penetration were then considered. In these scenarios, DG units are built to replace coal fire plants, while the total generation capacity remains identical. In scenario 1, DG units constitute around 10% of the system capacity (100MW), but we assume that DG units are non-dispatchable and their electricity is only consumed locally. They are therefore modeled as negative loads. The expansion cost distribution is illustrated in Fig. 8. Clearly, the maximum expansion cost of scenario 1 (350M$) is much lower than the base case (1400M$). Moreover, based on Figs 7 and 8, there is a 70% probability that the expansion cost of Scenario 1 is lower than the base case. These results strongly support the hypothesis that the introduction of DG can defer investments in transmission expansion.

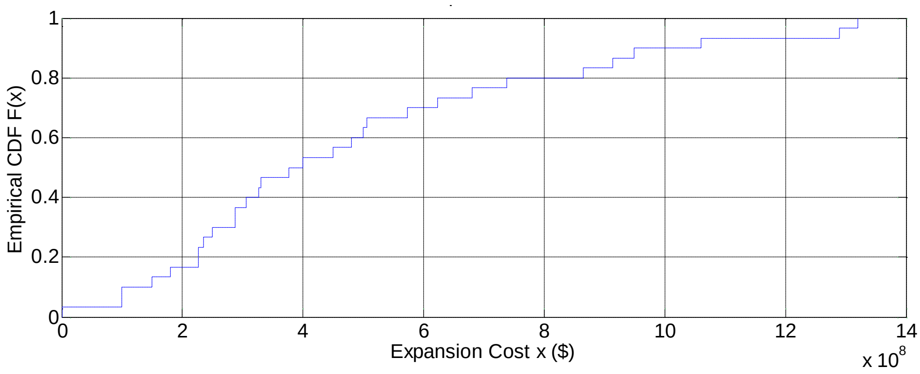

Figure 7 CDF of the Expansion Cost - No DG Installed

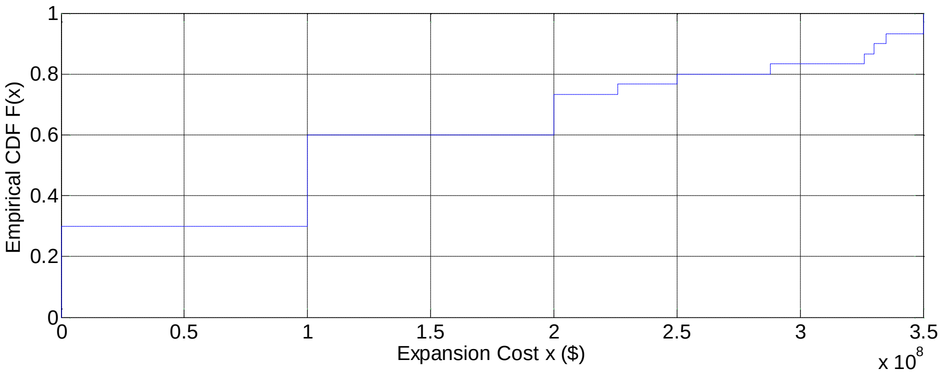

Figure 8 CDF of the Expansion Cost ï scenario 1 (10% Non-dispatchable DG Penetration)

Four different scenarios were also studied. In these scenarios, we assumed only wind or solar power will be implemented so as to investigate their specific performances in the market. Similarly, DG units replace coal fire plants but keep the total generation capacity unchanged. Unlike scenario 1, DG units were assumed to be dispatchable and traded through the spot market. In practice, involving DG units in the spot market may need modifications to the existing market dispatch process [31]. The expansion costs of four scenarios are given in Figs 9-12.

As observed, a 10% market share of dispatchable wind power and CST can still reduce future network expansion costs. However, the cost reductions are much lower than in the non-dispatchable case. These results are reasonable because when the DG units are involved in the dispatch process, their electricity will be traded through the transmission network, which potentially can cause network congestion and provide incentives for network expansion. However, compared with the base case, a 10% penetration level of DG can still defer transmission investments to some extent since most of their power is consumed locally. On the other hand, a 20% share of CST does not defer transmission investments, while a 20% share of wind power can even increase the transmission expansion cost in some situations. These results can largely be attributed to the relatively lower capacity factors of DG (especially wind power) compared with coal fired plants. When DG units are unavailable, most power is generated by coal fired plants located in a few generator buses, which worsens network congestion.

To better understand the impacts of DG, the simulated paths of congestion costs and EUE for different DG penetration levels are plotted in Figs 13 and 14. As observed, the base case without DG installed has a congestion cost ranging from 1000 to 5000. After DG units are built to replace coal fire plants, although the congestion cost still remains at the same level in most situations, DG does increase the probability of high congestion costs. This is especially the case for wind power (30% capacity factor). Since some coal fire plants have been replaced by DG units, the system relies on the remaining coal fire plants when wind power units are unavailable. This however increases the power flows on nearby transmission lines and hence worsen the congestion. Another possible explanation is that DG units will increase the nodal prices, which can also contribute to high congestion costs.

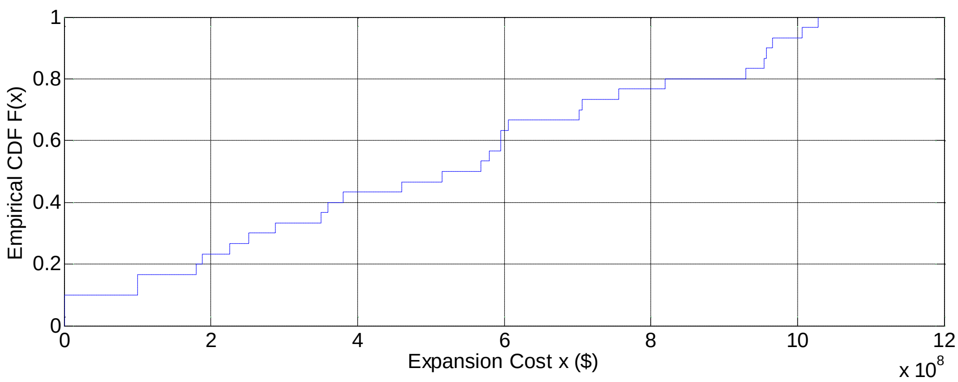

Figure 9 The Expansion Cost - Scenario 2 (10% Dispatchable Wind Power Penetration)

The EUE of different scenarios, as plotted in Fig. 14, are also compared. Surprisingly, the installation of DG units has not caused significant impacts on system reliability. This may be attributed to the sufficient generation capacity reserve. Therefore, to mitigate the impacts of DG on system reliability, it is necessary to build backup generators so as to maintain a sufficient generation reserve level.

V. CONCLUSION

How to expand the transmission network is an fundamental problem in the electricity market. In this paper, a novel method of transmission expansion planning has been proposed. This method employs two stochastic processes to model system loads and market prices. The values of different generation options in the network are calculated using load and price models. The generation options with higher values are selected to form a candidate generation options set on which generation uncertainty can be modeled. A transmission planning model based on AC OPF was introduced. A novel method based on Monte Carlo simulation was proposed to assess the flexibility of a candidate expansion plan and simulate transmission expansion behaviors under different market settings.

The proposed method was applied to investigate the impacts of distributed generation (DG) on transmission planning. Based on our results, DG can significantly defer transmission investments when it is not involved in the spot market. However, when DG reaches a high penetration level, its effect of deferring transmission investments is reduced. Moreover, a high level of DG penetration may increase the probability of network congestion, which might eventually require more transmission investments. A surprising result is that no significant impact of DG is observed on system reliability. This finding requires further careful investigation through appropriate model developments.

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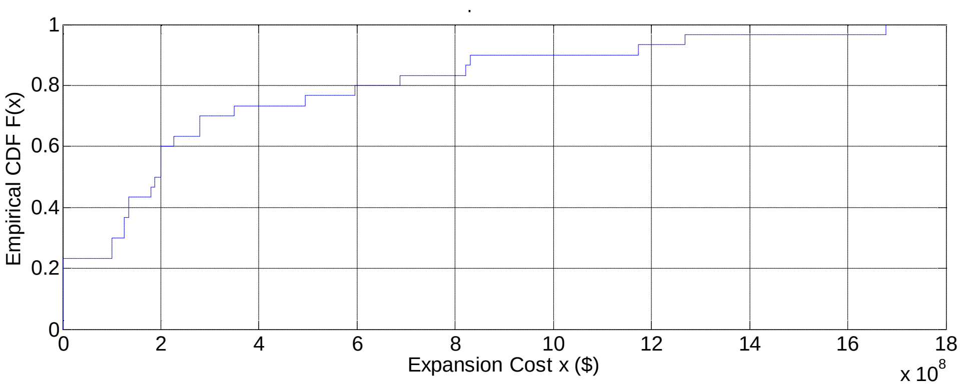


Figure 10 The Expansion Cost - Scenario 3 (20% Dispatchable Wind Power Penetration)

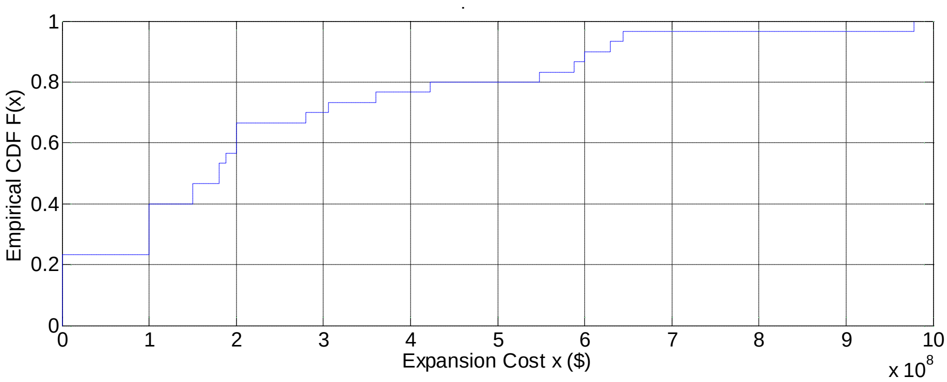


Figure 11 The Expansion Cost - Scenario 4 (10% Dispatchable CST Penetration)

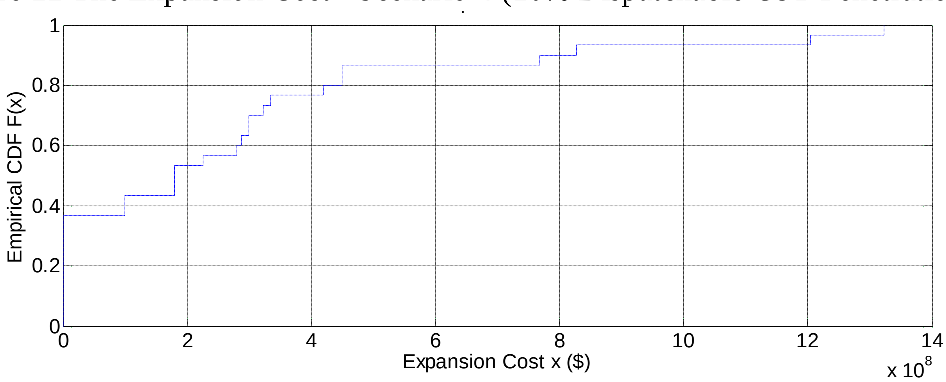
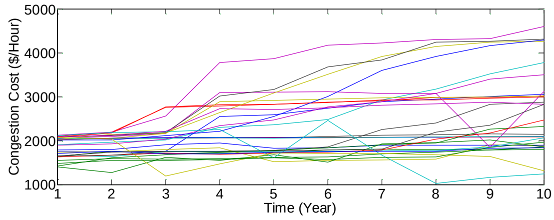
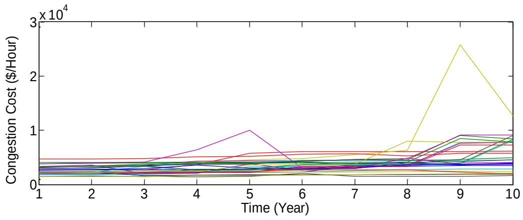


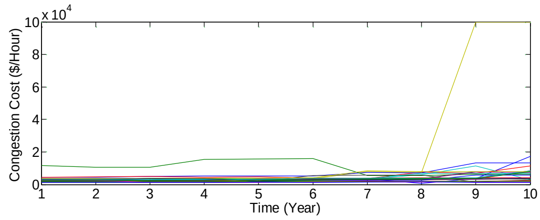
Figure 12 The Expansion Cost - Scenario 5 (20% Dispatchable CST Penetration)



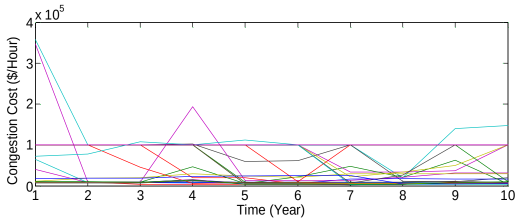
Base Case without DG



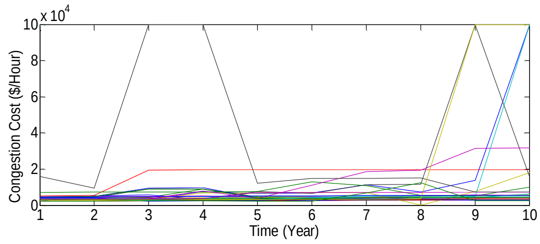
10% CST Penetration



20% CST Penetration

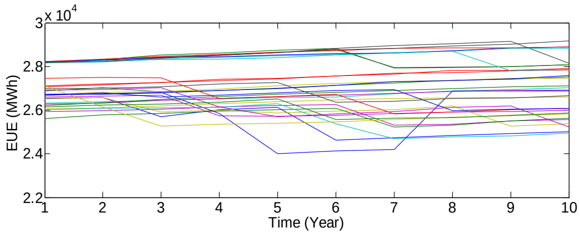


10% Wind Power Penetration

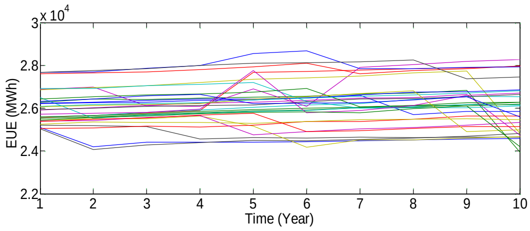


20% Wind Power Penetration

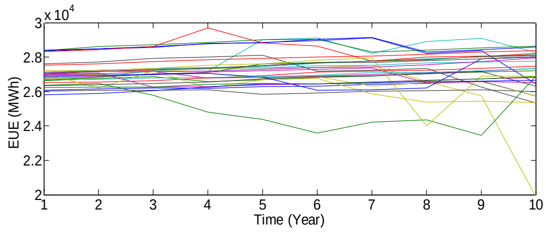
Figure 13 Congestion Costs for Different DG Penetration Levels



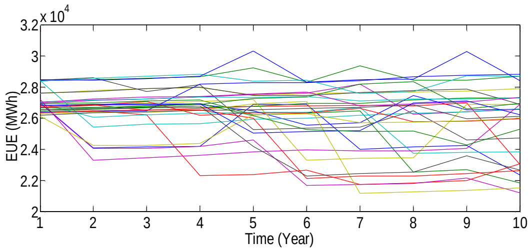
Base Case without DG



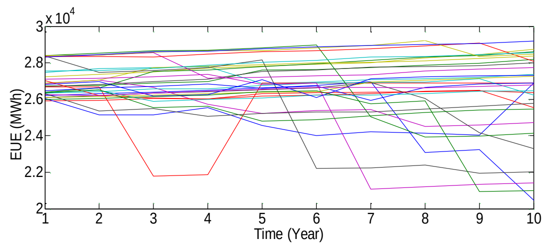
10% CST Penetration



20% CST Penetration



10% Wind Power Penetration



20% Wind Power Penetration

Figure 14 EUE for Different DG Penetration Levels